

3.0 MODELING PARAMETERS

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3.1 Selection and Justification of Modeling Parameters

All parameters used in modeling to demonstrate non-endangerment and "No-Migration" for the injection wells are discussed below along with a detailed explanation of how appropriate values were assigned. These values were then used to predict future wellbore and reservoir pressure in Section 5.1, and in lateral and vertical plume migration modeling in Sections 5.2 and 5.3.

The parameters used in the modeling to determine pressure buildup and "No-Migration" boundaries during the operational lives of the wells and for the 10,000-year period are listed in Table 3.1-I. The parameters have been grouped into the following categories: (1) formation matrix, (2) formation brine, (3) waste fluid, (4) operational factors, and (5) factors influencing waste migration. The formation matrix parameters for sand depth, net sand thickness, porosity, permeability, reservoir temperature, initial pressure, compressibility, and dip, are provided for the sand units within the injection interval. Properties of the confining shales are also discussed. Parameters associated with the formation brine include chemical composition, specific gravity, density, viscosity, and compressibility. The injected waste parameters include waste constituents and waste codes, density, viscosity, health-based-limit concentrations (HBLs), detection limits (DLs), maximum wellhead concentrations, concentration reduction factors, and general compatibility considerations. Operational factors include injection rates and volumes, anticipated well life, and fracture gradient and maximum injection pressure. The final category addressing waste migration includes natural regional hydraulic gradient, reservoir geometry, plume movement caused by nearby oil and gas production, dispersion factors, dispersion and diffusion coefficients, critical pressure rise, and offset injection. The justification for the selection of parameter values in each of these categories is discussed in the remainder of this section.

3.2 Injection Sand Properties

The injection intervals are sands of the Frio Formation. The Frio Formation is subdivided into three intervals: the Upper Frio, the Middle Frio, and the Lower Frio. The occurrence of the Frio sands is shown on the logs of WDW-157, WDW-169, and WDW-249 (Appendices 2.2.1-1 through 2.2.1-7) and by the cross sections on Figures 2.1.4-1, 2.1.4-2, and 2.2.1-1.

Two injection intervals are requested at the site: the primary Lower Frio injection interval and the alternate Upper and Middle Frio injection interval. The two injection intervals are described below.

Thick, continuous sands in the Lower Frio interval are the primary injection intervals for Class I and Class II injection wells in the area of the injection site. The Lower Frio injection interval sands that are perforated at the site and into which injection occurs are named Sands 1, 2, 3, 4, 5, and 6. The top and base of the Lower Frio injection interval are at 6870 feet KB and 7505 feet KB respectively in WDW-157 and proposed WDW-407 (assuming the KB is 17 feet above ground level).

The Upper and Middle Frio injection interval is identified as an alternate injection interval at the site to allow for temporary injection if injection into the Lower Frio injection interval is not possible due to mechanical problems in the wells. The top and base of the Upper and Middle Frio injection interval are at 5530 feet KB and 6670 feet KB respectively in WDW-157 and proposed WDW-407 (assuming the KB is 17 feet above ground level). The Upper and Middle Frio injection interval consists of all the sands in Upper Frio and sands above Sand 0 in the Middle Frio.

The injection intervals are slightly calcareous, poorly sorted, indurated, very fine-grained to medium-grained quartz sands.

The Upper and Middle Frio injection interval is separated from the Lower Frio injection interval by an isolating shale barrier. The isolating shale barrier includes the following layers: shale below the base of the Upper and Middle Frio injection

interval to the top of Sand 0; Sand 0; and shale below Sand 0 to the top of the Lower Frio injection interval.

The injection zone includes the two injection intervals and the confining portion of the injection zone. The confining portion of the injection zone for the site has a constant thickness of at least 1200 feet. The top of the injection zone is a constant 1200 feet above the top of the Frio Formation. At the injection site, the top of the Frio Formation is approximately 100 feet above the top of the shallowest Upper Frio sand. Included in the confining portion is the Anahuac Formation, which is approximately 500 feet of claystone and shale that overlies the Frio Formation throughout the vicinity of the injection site. The character of the confining portion of the injection zone is shown on the cross sections in Figures 2.1.1-1, 2.1.4-2, and 2.2.1-1. Table 2.2.1-I lists the depths of the confining zone, the injection zone, and the injection intervals at the injection wells.

The base of the injection zone occurs at the base of the Frio Formation. Below the injection zone are the Vicksburg shales.

3.2.1 Depths

The injection interval sands are shown on the logs in Appendices 2.2.1-1 through 2.2.1-7. The depths of the injection intervals in the injection wells are provided in Table 2.2.1-I.

3.2.2 Net Thicknesses

Lower Frio Injection Interval

Three (3) net sand thicknesses are presented for each of the Lower Frio sands in Table 3.2.2-I. The first column represents the measured sand thickness from the geophysical well log of the injection well. The values in the second column are the average net sand thicknesses within a 3000-foot radius of the centroid of Vopak's WDW-157 and Texas Molecular's WDW-169. The values in the third column are the average net sand thicknesses within a 2.5-mile radius of the centroid of Vopak's WDW-157 and Texas Molecular's WDW-169. The average net thicknesses within

the 3000-foot radius and the 2.5-mile radius were determined by a planimetric computation made on the net sand isopach maps for each sand unit (Figures 2.2.6-1 through 2.2.6-4).

Average net sand thicknesses within a 3000-foot radius of the centroid of WDW-157 and WDW-169 are 93 feet for Sand 1, 80 feet for Sands 2 and 3, 76 feet for Sand 4, and 177 feet for Sands 5 and 6. The total of these average net thicknesses within the 3000-foot radius is 426 feet.

Average net sand thicknesses within a 2.5-mile radius of the centroid of WDW-157 and WDW-169 are 71 feet for Sand 1, 79 feet for Sands 2 and 3, 82 feet for Sand 4, and 157 feet for Sands 5 and 6. The total of these average net thicknesses within the 2.5-mile radius is 389 feet.

For the Lower Frio injection interval, pressure buildup calculations in Section 5.1 are based on a conservatively low net sand thickness of 142 feet. Plume migration calculations in Section 5.2 are based on net sand thickness of 70 feet.

Upper and Middle Frio Injection Interval

The character and continuity of the Frio sands above the top of the Lower Frio are shown on the cross sections on Figures 2.1.4-1, 2.1.4-2, and 2.2.1-1. Figure 2.2.1-2 is a net sand isopach map of the Upper Frio "A" sands, which are continuous over a large area around the injection site. The Upper and Middle Frio injection interval consists of the Sand A (150 feet), Sand B (60 feet) and Sand C (65 feet) of Upper Frio and sands of the Middle Frio, excluding Sand 0 (145 feet). The approximate net sand thickness in the Middle and Upper Frio injection interval is 415 feet at WDW-157 (Figures 2.1.4-1 and 2.1.4-2).

For the Upper and Middle Frio injection interval, pressure buildup calculations assume a conservatively low net sand thickness of 50 feet. Plume migration calculations assume a conservatively low net sand thickness of 50 feet.

3.2.3 Porosity

The average porosity of sands in the injection intervals was determined from core data obtained in wells in the vicinity of the injection wells. Core data available for review included sidewall core analysis from WDW-157, WDW-169 (original hole), and WDW-222; and whole core data from WDW-169 (original hole), WDW-223, and WDW-249. Porosities for the core samples from each of the wells within an individual sand unit were averaged together to obtain an average porosity value for that sand unit. The average porosity of Sand 0 of the Middle Frio unit is presented on Table 3.2.3-I. Tables 3.2.3-II through 3.2.3-V present these data for Sands 1 through 5-6, respectively. Copies of the original core analysis reports for WDW-157, WDW-169 (original hole, sidewall cores and mineralogy), WDW-249, WDW-169 (original hole, whole core), and WDW-223 are included in Appendix 3.2.3-1 (the WDW-222 core report was not readily available during a 2014 search of the TCEQ's files). The porosity assigned to the sands is 32.4% for Sand 0, 30.1% for Sand 1, 29.6% for Sand(s) 2-3, 28.6% for Sand 4, and 28.8% for Sand(s) 5-6.

The average porosity of the sand units in the Upper and Middle Frio injection interval was determined from the density-porosity and neutron-porosity logs of WDW-249. A copy of the open-hole log of WDW-249 is included in Appendix 2.2.1-7. Porosity may be determined from the combination compensated-neutron-log (CNL) porosity and formation-density-compensated-log (FDC) porosity by the root-mean-square formula (Appendix 3.2.3-3, Asquith, 1980, pages 46-47). Density-porosity and neutron-porosity readings were determined in 10 sandy intervals with a minimum thickness of 3 feet in which the wellbore was not washed out or enlarged, as shown by the differential caliper curve on the open-hole log. The sands occurred in the Upper Frio unit between 5596 feet KB and 6320 feet KB in WDW-249. Appendix 3.2.3-2 lists the log-porosity readings in the sand intervals of the Upper Frio unit and the root-mean-square porosity calculation. The root-mean-square porosity values in these sand intervals range from 27.2% to 36.5%. The thickness-weighted average sand porosity in the sand intervals of the Upper Frio is 31.9%.

Modeling of reservoir pressure buildup and plume migration in both the Lower Frio injection interval and the Upper and Middle Frio injection interval is based on a conservatively low porosity of 28%.

3.2.4 Permeability

The measurements of permeability to air of core samples recovered from the Lower Frio injection interval and Sand 0, which occurs in the shaly interval between the two requested injection intervals, are listed in Tables 3.2.3-I through 3.2.3-V. The core reports are included as Appendix 3.2.3-1.

Analysis of annual pressure transient tests (1999 through 2014) from Vopak's WDW-157 has resulted in permeabilities ranging from a low of approximately 198 md to a high of 2591 md as shown in Table 3.2.4-I. Annual pressure transient test analysis on TMDPS's WDW-169 and WDW-249 through 2014 has resulted in permeabilities ranging between 203 md and 2136 md as shown in Tables 3.2.4-II and 3.2.4-III. The median permeability of the falloff tests was 1216 md. Excerpts from the falloff testing reports for WDW-157, WDW-169, and WDW-249 are included in Attachment A.

The early WDW-157 test reports (1988 through 1991) did not provide an analysis. An analysis summary including semi-log and log-log plots is included preceding each of these reports in Attachment A. WDW-169 reports for 1988, 1989, and 1990 were not included, and are not available; however, the falloff data was available and summaries with semi-log and log-log plots are included in Attachment A. The information presented in Tables 3.2.4-I through 3.2.4-III is based on consistent values for porosity, reservoir brine viscosity, and total compressibility. The injection interval thickness for each test is based on fill depth at the time of the test. The permeability values shown in the tables may differ from the value shown in the reports in Attachment A because they are based on the revised reservoir brine viscosity and thickness values. The log-log and semi-log plots are not affected by the change in viscosity or thickness. The formation skin damage was re-calculated to reflect the revised value for permeability, in addition to the revised viscosity, porosity and total compressibility.

The 1991 falloff test for WDW-157 was re-evaluated. A summary with log-log and semi-log plots precedes this report in Attachment A. The 1991, 2004, and 2005 tests on WDW-169 were re-evaluated. A summary, including log-log and semi-log plots precedes each of these reports in Attachment A. The 1993, 1998, 2004 and 2005 falloff tests for WDW-249 were also re-evaluated in addition to the 2001 interference test. A summary including plots precedes each of these tests.

Modeling of pressure buildup for the 2007 submittal employed a conservatively low permeability of 120 md for an infinite acting reservoir, and 300 md for a reservoir with one non-transmissive fault located 3000 feet NNW of WDW-157 and WDW-407 and 5000 feet NNW of TMDPS's WDW-169 and WDW-249 in order to maximize reservoir pressurization. Following the EPA's review, and examination of No-Migration petitions at nearby facilities, a value of 625 md was chosen for additional pressure modeling for this submittal.

Modeling of plume migration utilized a conservatively high permeability of 2500 md to maximize migration distance. The SWIFT code utilized for modeling plume migration does not employ permeability, but rather, hydraulic conductivity. Freeze and Cherry (1979) present the relationship between hydraulic conductivity and permeability as:

$$K = k\rho g/\mu$$

where

K = hydraulic conductivity, L/T

k = permeability, L^2

ρ = density of resident fluid, M/L^3

g = acceleration due to gravity, L/T^2

μ = viscosity, M/LT

The SWIFT input for hydraulic conductivity is in units of feet/day (ft/day), and in order to obtain this, a conversion constant needs to be determined:

$$\begin{aligned} \text{constant} &= \left(\frac{D}{1000 \text{ md}} \right) \left(9.869 \times 10^{-9} \frac{\text{cm}^2}{D} \right) \left(980 \frac{\text{cm}}{\text{sec}^2} \right) \\ &\quad * \left(\frac{\text{ft}}{30.48 \text{ cm}} \right) \left(\frac{60 \text{ sec}}{\text{min}} \right) \left(\frac{60 \text{ min}}{\text{hr}} \right) \left(\frac{24 \text{ hr}}{\text{day}} \right) \div \left(0.01 \frac{\text{g/cm} - \text{sec}}{\text{cp}} \right) \\ &= 0.00274 \frac{\text{ft/day}}{(\text{cm})(\text{g/cm}^3)/\text{cp}} \end{aligned}$$

Thus, the equation is:

$$K = 0.00274 \text{ kp}/\mu$$

where

- K = hydraulic conductivity, ft/day
- k = permeability, md
- ρ = density, g/cm³
- μ = viscosity, cp

The plume migration models use a permeability of 2500 md, a fluid density of 1.062 g/cm³, and a viscosity of 0.4681 cp (top of Sand 1), which results in a hydraulic conductivity of 15.54 ft/day.

3.2.5 Temperature

The temperature distribution for the injection intervals was calculated using the equation developed by Asquith and Gibson (1982):

$$y = mx + c$$

where

- y = temperature at the level of interest, °F
- m = geothermal gradient, °F/100 feet
- x = depth to the level of interest, ft
- c = average annual surface temperature, °F

The geothermal gradient was determined from the temperature of 176.5°F that was measured at 7287 feet BGL (7300 feet KB) in WDW-157 on February 18, 1980, during static bottom-hole pressure testing upon completion of the well. The static temperatures and pressures measured prior to the pump-in test are included as Appendix 3.2.6-1. Using the equation of Asquith and Gibson (1982), and assuming an average annual surface temperature of 74°F, the average temperature gradient derived from the WDW-157 temperature measurement is 0.0141°F/foot. The temperature equation for the injection site is:

$$\text{BHT} = 74^{\circ}\text{F} + (0.0141^{\circ}\text{F/foot})(\text{depth, feet BGL})$$

The temperature at the top of the Upper and Middle Frio injection interval at a depth of 5517 feet BGL is:

$$\begin{aligned}\text{BHT}_{5517\text{ ft}} &= 74^{\circ}\text{F} + (0.0141^{\circ}\text{F/foot})(5517\text{ feet BGL}) \\ &= 151.8^{\circ}\text{F} (66.6^{\circ}\text{C}) \text{ at } 5517\text{ feet BGL}\end{aligned}$$

The temperature at the top of Sand 1 at a depth of 6862 feet BGL:

$$\begin{aligned}\text{BHT}_{\text{Sand 1}} &= 74^{\circ}\text{F} + (0.0141^{\circ}\text{F/foot})(6862\text{ feet BGL}) \\ &= 170.8^{\circ}\text{F} (77.1^{\circ}\text{C}) \text{ at } 6862\text{ feet BGL}\end{aligned}$$

The temperature at the top of Sand 6 at a depth of 7267 feet BGL is:

$$\begin{aligned}\text{BHT}_{\text{Sand 6}} &= 74^{\circ}\text{F} + (0.0141^{\circ}\text{F/foot})(7267\text{ feet BGL}) \\ &= 176.5^{\circ}\text{F} (80.3^{\circ}\text{C}) \text{ at } 7267\text{ feet BGL}\end{aligned}$$

3.2.6 Original Bottom-Hole Pressure

The original reservoir pressure in WDW-157 was measured on February 18, 1980. The recorded pressure was 3187.84 psia at 7300 feet KB (7287 feet BGL). Appendix 3.2.6-1 contains the measured pressure data set from the WDW-157 drilling and completion report that verifies the original pressure and measurement depth.

The reservoir fluid density is approximately 1.062 g/cm³ at reservoir conditions (Section 3.4.3), which is equivalent to 1.064 specific gravity at reservoir conditions [1.064 = (1.062 g/cm³)/(0.998234 g/cm³)]. Extrapolating upward from 7287 feet BGL to the top of Sand 1 at 6862 feet BGL in WDW-157:

$$P_{6862} = P_{7287} + (0.433 \text{ psi/ft}) (\gamma_{\text{brine}}) (6862 \text{ feet BGL} - 7287 \text{ feet BGL})$$

where

$$\begin{aligned} P_{6862} &= \text{calculated bottom-hole pressure at 6862 feet BGL} \\ P_{7287} &= \text{measured pressure at 7287 feet BGL} \\ \gamma_{\text{brine}} &= \text{reservoir brine specific gravity} \end{aligned}$$

Substituting,

$$\begin{aligned} P_{6862} &= 3187.84 \text{ psia} + (0.433)(1.064)(6862 \text{ feet BGL} - 7287 \text{ feet BGL}) \\ &= 2992.04 \text{ psia at 6862 feet BGL (2977.34 psig, 206.29 bars)} \end{aligned}$$

Similarly, at the top of Sand 1 in WDW-169 at 6853 feet BGL, the original reservoir pressure is estimated to be 2987.89 psia.

$$\begin{aligned} P_{6853} &= 3187.84 \text{ psia} + (0.433)(1.064)(6853 \text{ feet BGL} - 7287 \text{ feet BGL}) \\ &= 2987.89 \text{ psia at 6853 feet BGL} \end{aligned}$$

At the top of Sand 1 in WDW-249 at 6854 feet BGL, the original reservoir pressure is estimated to be 2988.35 psia.

$$\begin{aligned} P_{6854} &= 3187.84 \text{ psia} + (0.433)(1.064)(6854 \text{ feet BGL} - 7287 \text{ feet BGL}) \\ &= 2988.35 \text{ psia at 6854 feet BGL} \end{aligned}$$

The pressure at 5517 feet BGL (the base of the confining layer) is calculated to be 2372.38 psia:

$$\begin{aligned}
 P_{5517} &= 3187.84 \text{ psia} + 0.433 (1.064) (5517 \text{ feet BGL} - 7287 \text{ feet BGL}) \\
 &= 2372.38 \text{ psia} (2358.68 \text{ psig}, 163.57 \text{ bars})
 \end{aligned}$$

Similarly, the pressure at 5524 feet BGL in WDW-249 is calculated to be 2375.60 psia.

$$\begin{aligned}
 P_{5524} &= 3187.84 \text{ psia} + (0.433)(1.064)(5524 \text{ feet BGL} - 7287 \text{ feet BGL}) \\
 &= 2375.60 \text{ psia}
 \end{aligned}$$

3.2.7 Formation Compressibility and Total Compressibility

The compressibility for the injection interval rock (c_r), using a correlation from Newman (1973) on Figure 3.2.7-1, is estimated to be $3.20 \times 10^{-6} \text{ psi}^{-1}$ using a porosity of 28%. The total effective compressibility (c_t) is expressed as:

$$c_t = c_r + c_w \quad \text{Equation 3.2.7-1}$$

where

$$\begin{aligned}
 c_t &= \text{total effective compressibility (psi}^{-1}\text{)} \\
 c_r &= \text{compressibility of injection interval rock (psi}^{-1}\text{)} \\
 c_w &= \text{compressibility of water (psi}^{-1}\text{)}
 \end{aligned}$$

The compressibility for water (c_w), is estimated to be $2.49 \times 10^{-6} \text{ psi}^{-1}$ (Section 3.4.5). The total effective compressibility resulting from addition of these two values is $5.69 \times 10^{-6} \text{ psi}^{-1}$ based on a porosity of 28%, a temperature of 170.8°F, and a pressure of 2992.04 psia at the top of Sand 1 at 6862 feet BGL:

$$\begin{aligned}
 c_t &= 3.20 \times 10^{-6} \text{ psi}^{-1} + 2.49 \times 10^{-6} \text{ psi}^{-1} \\
 &= 5.69 \times 10^{-6} \text{ psi}^{-1}
 \end{aligned}$$

3.2.8 Dip

The structure map at the top of Sand 1 (Figure 2.1.5-2) was used to determine variations in dip that will influence plume migration in the Lower Frio injection

interval. Each leg of the changing dip is shown on Figure 2.1.5-2. The segments were drawn to maximize the dip in both the updip and downdip directions. Table 3.2.8-I summarizes the distance and dip angle for each leg of the Lower Frio structure. Similarly, the structure map of the top of the Upper Frio (Figure 2.1.5-1) was used to determine the dip for modeling plume migration in the Upper and Middle Frio injection interval. Table 3.2.8-II summarizes the distances and dip angle for each leg of the Upper Frio structure.

3.3 Confining Shale Properties

Shales are composed of montmorillonite, kaolinite, illite, chlorite, and mixed layer smectite-illite (Curry, 1960). Siltstones are intermediate both in composition and grain size between sandstone and shale. Permeability to brine was measured at 1.6×10^{-6} md and 1.5×10^{-6} md in two shale cores from the Texas Molecular WDW-249 (Appendix 3.2.3-1). Additional empirical permeability data measured from Gulf Coast shale cores by Subsurface and Core Labs indicate shale permeabilities on the order of 6×10^{-5} md to 1×10^{-6} md. These data are listed in Table 3.3-I. For modeling purposes, a conservative value of 1×10^{-4} md has been chosen.

The porosity of the shales in the confining units above the injection interval sands ranges between approximately 18% and 36%, with porosity decreasing with depth, as indicated by porosity logs. The density-porosity curve in confining shales in the porosity log of WDW-249 (Appendix 2.2.1-7) indicates that the shale porosity in the injection zone above Sand 1 ranges from 20% to 32%, while the porosity of shales below Sand 1 ranges from 18% to 24%. The porosity of shale in the Anahuac Formation is approximately 30%. Above the Anahuac Formation, the porosity of shales in the confining zone ranges from 24% to 36%, as determined from the porosity log in Appendix 2.2.1-6.

3.4 Formation Brine Properties

3.4.1 Injection Interval Water Analysis

Formation fluid samples were taken from WDW-157 and WDW-169 from perforations in Lower Frio sands during the initial completion of the wells. Tables 3.4.1-I and 3.4.1-II contain the results of the analysis of the samples.

3.4.2 Specific Gravity of Formation Brine Sample

The formation brine samples from WDW-157 and WDW-169 had reported brine specific gravity values of 1.080 (Table 3.4.1-I) and 1.0836 (Table 3.4.1-II).

3.4.3 Density of Formation Brine Sample

Density

A brine with a specific gravity of 1.080 at 68°F and one atmosphere has an equivalent density of 1.078 g/cc (1.080×0.998234 g/cc), which corresponds to a 11% NaCl solution by weight (Table 3.4.3-I). Table 3.4.3-II presents the densities of 11% by weight solutions of NaCl at various temperatures and pressures (Potter and Brown, 1977) and is used to calculate the reservoir brine density at reservoir conditions. The following equation is used:

$$\begin{aligned} \rho_R = \rho_1 + (\rho_2 - \rho_1) \left(\frac{T_R - T_1}{T_2 - T_1} \right) + (\rho_3 - \rho_1) \left(\frac{P_R - P_1}{P_2 - P_1} \right) \\ + [(\rho_4 - \rho_3) - (\rho_2 - \rho_1)] \left(\frac{T_R - T_1}{T_2 - T_1} \right) \left(\frac{P_R - P_1}{P_2 - P_1} \right) \end{aligned}$$

where

ρ_R = density at reservoir temperature and pressure, g/cc

T_1 = temperature in Table 3.4.3-II lower than reservoir temperature

T_2 = temperature in Table 3.4.3-II higher than reservoir temperature

P_1 = pressure in Table 3.4.3-II lower than reservoir pressure

- P_2 = pressure in Table 3.4.3-II higher than reservoir pressure
 ρ_1 = density at temperature T_1 and P_1 in Table 3.4.3-II
 ρ_2 = density at temperature T_2 and P_1 in Table 3.4.3-II
 ρ_3 = density at temperature T_1 and P_2 in Table 3.4.3-II
 ρ_4 = density at temperature T_2 and P_2 in Table 3.4.3-II

The reservoir brine density at the top of Sand 1 (170.8°F, 77.1°C; 2992.04 psia, 206.29 bars) is:

$$\begin{aligned}
 \rho_R &= 1.063 + (1.048 - 1.063) \frac{(77.1 - 75)}{(100 - 75)} + (1.065 - 1.063) \left(\frac{206.29 - 200}{300 - 200} \right) \\
 &\quad + [(1.051 - 1.065) - (1.048 - 1.063)] \left(\frac{77.1 - 75}{100 - 75} \right) \left(\frac{206.29 - 200}{300 - 200} \right) \\
 &= 1.063 - 0.001260 + 0.000126 + 0.00000528 \\
 &= 1.062 \text{ g/cm}^3 (66.30 \text{ lb/ft}^3)
 \end{aligned}$$

Modeling calculations in this document were performed assuming a formation brine density of 66.30 lb/ft³ (1.062 x 62.427961).

3.4.4 Viscosity of Formation Brine

The value of the viscosity for the formation brine (11% NaCl) at reservoir temperature (170.8°F) was determined using the equations from the HP-41 Petroleum Fluids Pak (Appendix 3.4.4-1), in addition to the following equation:

$$\mu = \mu_T^* f$$

where

- μ = viscosity at reservoir temperature and pressure, cp
 μ_T^* = viscosity at reservoir temperature and atmospheric pressure, cp
 f = viscosity correction factor due to pressure

Figure 3.4.4-1 presents viscosities determined from Appendix 3.4.4-1 in the same format as texts such as Matthews and Russell, Earlougher, and Lee.

Table 3.4.4-I lists the reservoir brine viscosity at 170.8° F, in addition to viscosities at various depths in the reservoir.

3.4.5 Compressibility of Formation Brine

The formation brine compressibility, c_w , was estimated from the Long and Chierici correlation presented by Earlougher (1977) and shown as Figure 3.4.5-1. The reservoir brine can be represented by an 11% NaCl solution, which is equivalent to a 110,000 ppm NaCl solution. The temperature and pressure in Sand 1 (170.8° F and 2977.34 psig) were used in determining c_w for 100,000 ppm (2.52×10^{-6} psi⁻¹) and 200,000 ppm (2.24×10^{-6} psi⁻¹) NaCl solutions. These values were used to interpolate the compressibility for a 110,000 ppm NaCl solution. The resulting formation brine compressibility is 2.49×10^{-6} psi⁻¹.

3.5 Wastestream Properties

The injection wells are currently approved to inject the wastes described in Section 1.3.4.

3.5.1 Hazardous Waste Constituents and Waste Codes

Hazardous waste components with waste codes that may be found in the waste stream are listed in Table 3.5.1-I.

3.5.1.1 Health-Based Limit (C_{HBL}) and Detection Limits

Each chemical compound in Table 3.5.1-I has either a Land Ban Health-Based Limit concentration (C_{HBL}) or a detection limit (DL). HBLs and DLs are those from the April 25, 2005, USEPA Region 6 Land Ban Health-Based Limit Guidelines.

3.5.1.2 Maximum Wellhead Concentration (C_0)

The worst-case health-based concentration reduction factor (C_{HBL}/C_0) for this site is set at 7×10^{-11} , where C_{HBL} is the concentration of a particular molecule at an assigned HBL. C_0 is the maximum petitioned wellhead concentration for that particular molecule. The maximum wellhead concentration is set equal to:

$$C_0 = C_{HBL}/(7 \times 10^{-11})$$

For compounds without specified HBLs, the value of the detection limit is used in place of the C_{HBL} . As can be seen by reviewing Table 3.5.1-I, the maximum wellhead concentration for the majority of the compounds is equivalent to the pure product (1×10^6 mg/l). Since the injected fluid is basically an aqueous brine contaminated with total organic substances at concentrations less than 10,000 mg/l due to their solubility, the high wellhead concentrations actually are evidence of the conservatism utilized in the approach taken at this site for setting maximum wellhead concentrations and for the estimation of the "No-Migration" plume boundary.

3.5.1.3 Concentration Reduction Factor (C_{HBL}/C_0)

A concentration reduction factor of 7×10^{-11} reflects the worst-case concentration reduction factor for the waste stream injected at this site. For a compound with no specified HBL, the DL was used to calculate its concentration reduction factor.

3.5.2 Specific Gravity

Vopak's waste density will fall within the range of 0.950 g/cm^3 to 1.250 g/cm^3 at surface conditions of 68°F (20°C) and atmospheric pressure. Corresponding specific gravity ranges at measurement temperatures of 68°F and 60°F (15.6°C) referenced to the density of fresh water at 4°C , 15.6°C , and 20°C are listed in Table 3.5.2-I.

Conversion between density and specific gravity is accomplished from the following:

$$\gamma_{I,20^{\circ}} = \frac{\rho_{I,20^{\circ}}}{\rho_{FW,4^{\circ}}}$$

where,

$\gamma_{I,20^{\circ}}$ = injectate specific gravity at 20° C

$\rho_{I,20^{\circ}}$ = injectate density at 20° C

$\rho_{FW,4^{\circ}}$ = fresh water density at 4° C = 0.99997 g/cm³

A fluid with a density of 0.950 g/cm³ at 20°C has a specific gravity of 0.950 when measured at 20°C and referenced to the density of fresh water at 4°C:

$$\begin{aligned}\gamma_{I,20^{\circ}} &= \frac{\rho_{I,20^{\circ}}}{\rho_{FW,4^{\circ}}} \\ &= \frac{0.950}{0.99997} \\ &= 0.950\end{aligned}$$

A fluid with a density of 1.250 g/cm³ at 20°C has a specific gravity of 1.250 when measured at 20°C and referenced to the density of fresh water at 4°C:

$$\begin{aligned}\gamma_{I,20^{\circ}} &= \frac{\rho_{I,20^{\circ}}}{\rho_{FW,4^{\circ}}} \\ &= \frac{1.250}{0.99997} \\ &= 1.250\end{aligned}$$

Table 3.5.2-I lists the ranges of injectate specific gravities and densities requested for this site. Specific gravity and density at 60°F are calculated in Appendix 3.5.2-I.

3.5.3 Density

The injectate fluid densities determined in this section for use in modeling were derived from an injectate density range of 0.950 g/cm³ to 1.250 g/cm³ under surface temperature and pressure conditions of 20° C (68° F) and 1 atm.

The following will describe the method used to determine the density at reservoir conditions of 170.8° F (77.1° C) and 2992.04 psia (206.29 bars) at the top of Sand 1.

3.5.3.1 Downhole Density of the Minimum Density Injectate

The minimum density injectate is a 0.950 g/cm³ fluid at a surface temperature of 20°C and 1 atm pressure. The calculation of the density of this fluid to downhole conditions is then based on the assumption that the ratio of densities between fresh water and the injectate remains constant:

$$\frac{\rho_{I(77.1^{\circ}\text{C}, 206.29 \text{ bars})}}{\rho_{\text{fw}(77.1^{\circ}\text{C}, 206.29 \text{ bars})}} = \frac{\rho_{I(20^{\circ}\text{C}, 1 \text{ atm})}}{\rho_{\text{fw}(20^{\circ}\text{C}, 1 \text{ atm})}}$$
$$\rho_{I(77.1^{\circ}\text{C}, 206.29 \text{ bars})} = \rho_{\text{fw}(77.1^{\circ}\text{C}, 206.29 \text{ bars})} \times \frac{\rho_{I(20^{\circ}\text{C}, 1 \text{ atm})}}{\rho_{\text{fw}(20^{\circ}\text{C}, 1 \text{ atm})}}$$

The density of fresh water (ρ_{fw}) at 77.1°C and 206.29 bars is calculated by interpolation of the data listed in Tables 3.5.3.1-I and 3.5.3.1-II, which are from Lange's Handbook of Chemistry, 12th Edition, 1973, Pages 10-91 and 10-122, respectively. Table 3.5.3.1-I indicates that the density of water at 0°C is 0.99984 g/cm³. Table 3.5.3.1-II reports the volume of water at various temperatures and pressures relative to the volume of 1.000 g/cm³ for water at 0°C. Thus, the density of water at any temperature is given by dividing 0.99984 by the volume of water given in Table 3.5.3.1-II. At 20°C and 1 atmosphere pressure, the density of water is found to be:

$$0.99984 \text{ g}/1.0016 \text{ cm}^3 = 0.9982 \text{ g/cm}^3.$$

This is the same value for the density of water at 20°C that is presented in Table 3.5.3.1-I.

The density of fresh water (ρ_{fw}) at 77.1°C and 210.36 atm using Table 3.5.3.1-II, is given by the expression:

$$\rho_{fw}(77.1^\circ\text{C}, 206.29 \text{ bars}) = \rho_{fw}(60^\circ\text{C}, 1 \text{ atm}) + \Delta\rho$$

where

$$\rho_{fw}(60^\circ\text{C}, 1 \text{ atm}) = 0.98320 \text{ g/cm}^3 \text{ (Table 3.5.3.1-I), and}$$

$$\Delta\rho = \Delta T \left(\frac{\Delta\rho}{\Delta T} \right)_p + \Delta P \left(\frac{\Delta\rho}{\Delta P} \right)_T + \Delta P \Delta T \left(\frac{\Delta^2\rho}{(\Delta T)_p (\Delta P)_T} \right)$$

Using Table 3.5.3.1-I yields:

$$\begin{aligned} \rho_{fw}(77.1^\circ\text{C}, 210.36 \text{ atm}) &= 0.98320 + (77.1 - 60) \left[\frac{(0.99984 / 1.0287 - 0.99984 / 1.0168)}{80 - 60} \right] \\ &\quad + (210.36 - 1) \left[\frac{(0.99984 / 0.9967 - 0.99984 / 1.0168)}{500 - 1} \right] \\ &\quad + (210.36 - 1)(77.1 - 60) \left[\frac{\left(\frac{0.99984}{1.0071} - \frac{0.99984}{1.0287} \right) - \left(\frac{0.99984}{0.9967} - \frac{0.99984}{1.0168} \right)}{(80 - 60)(500 - 1)} \right] \\ &= 0.98320 - 0.00973 + 0.00816 + 0.000357 \\ &= 0.98216 \text{ g/cm}^3 \end{aligned}$$

The density of the light injectate at formation conditions is calculated to be 0.935 g/cm³:

$$\begin{aligned}
 P_{I(77.1^{\circ}\text{C}, 210.36 \text{ atm})} &= 0.98216 \times \frac{0.950}{0.9982} \\
 &= 0.935 \text{ g/cm}^3 \\
 &= 58.37 \text{ lb/ft}^3
 \end{aligned}$$

3.5.3.2 Downhole Density of the Maximum Density Injectate

The maximum density injectate is a 1.250 g/cm³ fluid at surface conditions of 20°C and 1 atm pressure. This density is greater than the density of saturated NaCl brine. For calculation purposes, a 25 weight percent NaCl brine will be used to determine the density of the maximum density injectate at downhole conditions of 77.1° C and 206.29 bars.

The density of a 25 weight percent solution of NaCl at conditions of 20° C and atmospheric pressure is 1.1909 g/cm³ from Table 3.4.3-I.

Table 3.5.3.2-I provides the data required to estimate the density of this fluid under downhole conditions. Using Equation 3.4.3-1 with the values in Table 3.5.3.2-I yields:

$$\begin{aligned}
 T_1 &= 75^{\circ}\text{C} \\
 T_2 &= 100^{\circ}\text{C} \\
 P_1 &= 200 \text{ bars} \\
 P_2 &= 300 \text{ bars} \\
 \rho_1 &= 1.167 \text{ g/cm}^3 \\
 \rho_2 &= 1.152 \text{ g/cm}^3 \\
 \rho_3 &= 1.170 \text{ g/cm}^3 \\
 \rho_4 &= 1.155 \text{ g/cm}^3
 \end{aligned}$$

$$\begin{aligned}
\rho_{(77.1^{\circ}\text{C}, 206.29 \text{ bars}, 25\% \text{ NaCl})} &= 1.167 + (1.152 - 1.167) \left(\frac{77.1 - 75}{100 - 75} \right) \\
&\quad + (1.170 - 1.167) \left(\frac{206.29 - 200}{300 - 200} \right) \\
&\quad + \left[(1.155 - 1.170) - (1.152 - 1.167) \right] \left(\frac{77.1 - 75}{100 - 75} \right) \left(\frac{206.29 - 200}{300 - 200} \right) \\
&= 1.167 - 0.001260 + 0.000189 + 0.000000 \\
\rho_{(77.1^{\circ}\text{C}, 206.29 \text{ bars}, 25\% \text{ NaCl})} &= 1.166 \text{ g/cm}^3
\end{aligned}$$

Again, assuming the ratio of density at reservoir conditions to the density at 20° C is constant for the 25 weight percent NaCl brine and the maximum density injectate will lead to a density of 1.224 g/cm³ for the maximum density injectate at reservoir conditions:

$$\begin{aligned}
\rho_{I(77.1^{\circ}\text{C}, 206.29 \text{ bars})} &= \rho_{25\% (77.1^{\circ}\text{C}, 206.29 \text{ bars})} \times \frac{\rho_{I(20^{\circ}\text{C}, 1 \text{ atm})}}{\rho_{25\% (20^{\circ}\text{C}, 1 \text{ atm})}} \\
&= 1.166 \times \frac{1.250}{1.1909} \\
&= 1.224 \text{ g/cm}^3 \\
&= 76.41 \text{ lb/ft}^3
\end{aligned}$$

3.5.3.3 Brine/Injectate Density Contrast

The density of the formation brine is 1.062 g/cm³ at the top of Sand 1 (Section 3.4.3). The lowest petitioned waste density is 0.935 g/cm³ at Sand 1 (Section 3.5.3.1). The density contrast is, therefore, 0.127 g/cm³ at Sand 1. The highest density injectate has a density of 1.224 g/cm³ at Sand 1 (Section 3.5.3.2). The brine/injectate density contrast is, therefore, 0.162 g/cm³ at Sand 1.

3.5.4 Viscosity

The modeled injection waste fluid viscosity was determined from Appendix 3.4.4-1. The low-density injectate viscosities were assumed to be similar to 0% NaCl, while the high-density injectate was assumed to be similar to 26% NaCl. Table 3.5.4-I lists viscosities of the low-density injectate at various depth/pressure/temperature conditions. Table 3.5.4-II lists viscosities of the high-density injectate at various depths/pressures/temperatures.

3.5.5 Waste Compatibility

The information provided in this section demonstrates that no evidence, either theoretical or observed, exists to suggest that the waste or well treatment fluids injected at this site could cause wastes to migrate horizontally or vertically out of the injection zone due to chemical incompatibilities. The integrity of the sands and the shale in the injection interval is not threatened by either the injected waste or the concentrated acids used during stimulation treatments.

The worst-case scenarios presented in this section are extremely conservative and demonstrate that no potential exists for the injected wastes to approach the boundary limits of the injection zone.

The current monitoring system and physical limitations on injection, as established by the state and federal regulations, are adequate checks to identify and address any problems that might arise. Meeting the operating limits, such as maximum injection pressure; minimum differential well annular pressure versus injection pressure; and annulus fluid volume changes, all force the operator to be as protective of his wellbore and the injection zone as is possible. Furthermore, items such as tubing failures and packer failures, caused by the injection of corrosive materials, require shutdown of the well and a workover to be performed. The current monitoring methods are capable of detecting wellbore integrity and injection problems before they could threaten human health and the environment.

The areas of compatibility addressed in this section are:

- Waste Fluid - Formation Compatibility
- Wastestream - Formation Fluid Compatibility
- Wastestream Solids Content
- Compatibility of Well Treatment Acids with Formation

3.5.5.1 Waste Compatibility with the Formation and Formation Fluid

Injectate/Injection Interval Compatibility

In the Frio Formation, the intervals capable of receiving injected waste are composed of relatively unconsolidated sandstones. These sandstones are composed primarily of silica (SiO_2) sand grains. They contain thin interbedded shale layers that are composed of various clay minerals. Clay particles are also randomly disseminated within the sands. The sands are also slightly limy or calcareous due to minor amounts of calcite that is generally present as limestone grains, shell fragments, and calcite cement.

The shale intervals in the Frio Formation, as in other Gulf Coast formations, including the Anahuac, which is part of the confining portion of the injection zone, are composed of quartz, smectite, montmorillonite, and small quantities of other clays, feldspars, pyrite, and calcite (Gray and Darley, 1980, p. 381).

The porous portions of the injection interval, which directly receive fluids, are composed of approximately 80% to 90% by weight fine- to very fine-sand grains (with diameters ranging from 0.250 to 0.062 mm) and approximately 10% to 20% clay (with particle sizes less than or equal to 0.002 mm).

The clay minerals in these formations are capable of ion exchange reactions with heavy metals and adsorption/desorption reactions with organics (Callahan et al., 1979). Clay particles typically are elongated and tubular or sheet-like in form with large surface areas of exchangeable cations (Potter, et al., 1980). These available

cations readily bond with anions in the injectate. These reactions tend to reduce the concentration of the waste constituents in the plume.

The best evidence, to date, of compatibility between the injected fluids and the formation materials is the fact that the injection wells have not experienced excessive increases in formation pressure. Pressure falloff tests, summarized in Tables 3.2.4-I through 3.2.4-III, indicate that significant increases or decreases in transmissivity that may be attributable to compatibility problems have not occurred. If the injection fluid was leaching chemicals from the formation rock, the transmissivity would be expected to increase. Conversely, if material was being removed from the injectate by precipitation, the transmissivity would decrease. In addition, historical mechanical integrity testing of the injection wells has revealed no significant permeation of injected fluids out of the injection interval and into the confining portion of the injection zone. Excerpts from the historical mechanical integrity test reports for the wells are included in Attachment A. The report of the most recent mechanical integrity testing is summarized in Section 6.0. The complete reports of the tests are on file with EPA Region 6. Chemical incompatibility with the formation is not apparent.

Injectate/Formation Fluid Interactions

Simple dilution will be the primary result of mixing of injection fluid and formation brine. In the wells' injection history, no loss of injectivity has been determined to have resulted from wastestream interaction with formation fluid.

Wastestream Solids Content

The waste streams at the injection facility are filtered. However, the solids contents of the waste streams are still routinely sampled and measured. The current modeling and well test data indicate that, while the wells have occasionally experienced reductions in permeability in the near wellbore region due to wellbore fill from sand influx, this permeability loss has not caused operational problems.

3.5.5.2 Compatibility of Well Treatment Fluids with Formation

Formation/HCl Compatibility

Concentrated hydrochloric acid (HCl) has been used in acid treatments of WDW-157 to remedy plugging by solids. HCl will not react with the silica that forms the sand grains in the injection interval. HCl will, however, react with any calcite present in the formation. Because calcite is present only in very minor amounts in the sands, HCl will have a negligible affect on the formation.

Formation/HF Compatibility

In contrast to HCl, hydrofluoric acid (HF) is reactive with siliceous material (Williams et al., 1979; Shaughnessy and Kunze, 1981; Guin and Schechter, 1971; Smith and Hendrickson, 1965; Hall, 1978; and Crowe, 1986). The rapid reaction rate of the HF with the siliceous material, which results in the HF reacting completely in the injection interval, precludes the possibility of any significant portion of the injected HF from undergoing reaction with the shale interval. The basic reason for this is the difference between the very low permeability of the shale in the containment interval and the relatively high permeability of the injection interval sands. The injected fluid will take the path of least resistance and, therefore, will move preferentially into the more permeable injection interval.

Since the reaction is extremely fast, no long-term potential exists for this acid to remain active in the formation and migrate into the shale interval. Therefore, the injected HF is not expected to penetrate more than a few inches of the shale interval above the injection interval. If siliceous cement is present in the injection interval, then it will likely be removed, and sanding problems at the wellbore may occur.

3.5.5.3 Wastestream Corrosivity

The current monitoring and physical limitations on injection, as established by the federal and state regulations, are sufficient checks to identify and address problems

with compatibility that might arise. Operating limits, such as maximum injection pressure and requirements to monitor well annular volume and annular pressure versus injection pressure, force the operator to be protective of the wellbores. Furthermore, such events as tubing and packer failures caused by the injection of corrosive wastes will require shutdown of the well and a workover. It is in the best interest of the operator to avoid compatibility problems, because the integrity of the wells, an important source of income and a significant asset for this facility, is directly affected by compatibility. The current monitoring methods are capable of detecting wellbore integrity and other compatibility problems before they threaten human health and the environment.

3.6 Operational Factors

Operational factors that affect non-endangerment and plume migration include historical and future injection rates and volumes, maximum injection pressure, and wastestream properties (Section 3.5).

3.6.1 Injection Rate and Volume

Lower Frio Injection Interval

The average rate requested for the site is 450 gallons per minute (gpm). Based on 450 gpm and a 30-day month, the maximum monthly volume of injected waste for the site is:

$$(450 \text{ gal/min})(1440 \text{ min/day})(30 \text{ days/month}) = 19,440,000 \text{ gallons per month}$$

Upper and Middle Frio Injection Interval

The average rate requested for the site is 175 gpm. The maximum monthly volume to be injected into the Upper and Middle Frio injection interval is:

$$(175 \text{ gal/min})(1440 \text{ min/day})(30 \text{ days}) = 7,560,000 \text{ gallons per month}$$

Injection into the Upper and Middle Frio injection interval will be limited to a total volume of 183,960,000 gallons from this site.

3.6.2 Anticipated Future Life of Well

The wells are anticipated to inject until December 31, 2030.

3.6.3 Fracture Gradient and Maximum Injection Pressures

Actual data obtained by Farris in 1946 (Howard and Fast, 1970, Appendix 3.6.3-1) showed that a range of values were required to bracket the measured fracture gradients in the region necessary to extend a fracture. The fracture gradient to extend a fracture was observed to range between 0.58 and 0.85 psi/ft. The mean value was 0.725 psi/ft.

The maximum surface pressure that can be sustained without fracturing the injection interval can be determined by:

$$\text{MSIP} = P_t + P_f - P_r$$

where

MSIP = maximum surface injection pressure, pounds per square inch gauge (psig)

P_t = pressure drop due to friction loss in the tubing, psi

P_r = pressure due to the hydrostatic head, psi

P_f = pressure to fracture at top of the perforations, psi

If pressure drop due to friction loss in the tubing is ignored, then:

$$\text{MSIP} = P_f - P_r$$

The maximum injectate specific gravity requested is 1.250 at 68°F and 1 atm. Fracturing is most likely to occur at the shallowest depth in the injection interval

since the maximum injection pressure remains the same regardless of depth and hydrostatic head increases linearly with depth. Conservative calculations of MSIP at the top of the Upper and Middle Frio injection interval at 5517 feet BGL are given below.

$$\begin{aligned}P_r &= \text{Injectate Specific Gravity} \times 0.433 \text{ psi/ft} \times \text{Depth} \\&= 1.250 \times 0.433 \text{ psi/ft} \times 5517 \text{ feet} \\&= 2986 \text{ psi}\end{aligned}$$

Using a fracture gradient of 0.725 psi/ft, the maximum pressure that can be sustained without fracturing the formation at the base of the confining layer is:

$$\begin{aligned}P_f &= \text{Depth} \times \text{Fracture Gradient} \\&= 5517 \text{ feet} \times 0.725 \text{ psi/ft} \\&= 4000 \text{ psi}\end{aligned}$$

Then

$$\begin{aligned}\text{MSIP} &= 4000 \text{ psi} - 2986 \text{ psi} \\&= 1014 \text{ psi}\end{aligned}$$

An injection gradient of 0.700 psi/ft has been established for several other operators along the Texas Gulf Coast as a conservative value. When 0.700 psi/ft is used, a maximum fracture pressure of 3862 psi is the result.

$$P_f = 5517 \text{ feet} \times 0.700 \text{ psi/ft} = 3862 \text{ psi}$$

Then

$$\begin{aligned}\text{MSIP} &= 3862 \text{ psi} - 2986 \text{ psi} \\&= 876 \text{ psi}\end{aligned}$$

The requested injectate specific-gravity range is 0.950 to 1.250 at 68°F (20°C) referenced to the density of fresh water at 4°C and atmospheric pressure. To remain within an injection gradient of 0.700 psi/ft, surface injection pressure will be limited

relative to injectate specific gravity based on the following schedule:

Specific Gravity Range and Density (g/cm ³) Range at 68°F and 1 atm	Maximum Surface Injection Pressure (psig)
0.950 - 1.000	1473
1.000 - 1.050	1354
1.050 - 1.100	1234
1.100 - 1.150	1115
1.150 - 1.200	995
1.200 - 1.250	876

The maximum authorized surface injection pressure for a range of specific gravities is determined by:

$$\text{MSIP} = 3862 \text{ psi} - (0.433 \text{ psi/ft})(5517 \text{ feet}) \times (\text{specific gravity})$$

3.7 Factors Controlling Waste Migration

Waste migration will be influenced by the natural regional hydraulic gradient, reservoir geometry, fluid withdrawal associated with oil and gas production, dispersion factors, molecular diffusion, and the reservoir pressure increase due to injection by offset wells.

3.7.1 Natural Regional Hydraulic Gradient

The background reservoir flow rate in the downdip direction is assigned a value of 0.5 ft/yr, as discussed in previously approved petition submissions, and is used here for continuity. Natural aquifer flows are well documented in shallow aquifers, but reliable data for deep, confined aquifers have not generally been available. Limited studies in the Mt. Simon Formation by Nealson (1982) and Clifford (1973), and the Frio Formation on the Texas Gulf Coast by Kreitler, et al. (1988), demonstrate the complexities of the problem and limitations of conventional hydrological methods. Appendix 3.7.1-1 contains the papers by Kreitler, et al. (1988) and Clifford (1973).

As indicated by Kreitler, et al. (1988), the ability to determine the natural gradient along the Texas Gulf Coast has been compromised by the production of oil and gas from the injection formations. Basically, the natural hydraulic gradient has been overshadowed by the locally induced gradient from oil and gas production.

Although it would be difficult to determine the current natural hydraulic gradient for the Frio Formation, a conservative estimate can be made from previous studies. Data published by Clifford (1973, 1975), Slaughter (1981), and Bently (1986) provide estimated natural hydraulic gradients from three aquifers that are approximately 3000 feet deep. The natural hydraulic gradient in the aquifers ranged from 0.021 ft/yr to 1.58 ft/yr and averaged 0.7 ft/yr. For aquifers in the depth range of 6000 feet, the natural hydraulic gradient is estimated to be smaller and, as indicated by Kreitler (1988), to be on a geologic time scale. Therefore, based on this information, an estimate for the natural background reservoir velocity in the Frio Formation is conservatively placed at 0.5 ft/yr downdip, and is in an approximate southeasterly direction.

3.7.2 Faulting and Reservoir Geometry

Subsurface faulting has been discussed in Section 2.2.4. As indicated on Figures 2.1.5-1 and 2.1.5-2, Fault C trends west-southwest to east-northeast within 2000 feet to the north of WDW-157, WDW-169 and WDW-249. Discussions of how the fault is expected to affect reservoir pressure buildup and plume migration are presented in Section 5.0.

3.7.3 Plume Movement Caused By Nearby Oil and Gas Production

It must be stressed at this point that plume drift due to neighboring fluid withdrawals must occur during the active life of these withdrawal wells. Hence, this is essentially in the lifetime of the injection wells.

To establish the potential baseline effect due to the production of reservoir fluids, the total volume of oil, gas, and water that has been produced from the Frio Formation within a 20-mile radius has been investigated. The choice of a 20-mile radius was

based on a regional review of all oil and gas production in the area. Historical production records were obtained from the IHS Energy Division (formerly PI and Dwight's) for all oil and gas fields that have produced from the Frio Formation. Figure 3.7.3-1 is a map from IHS showing the locations of most of the oil (green) and gas (red) fields in the area. At the resolution of the map view available from IHS, some fields (Alligator Bayou, for example) are not shown, but production data for all Frio fields in the area are included in this analysis. Twenty-six (26) of the fields shown on Figure 3.7.3-1 of the injection site did not produce from the Frio; these fields are listed in Table 3.7.3-II. Historical production data from IHS for 1910 through July 2014 (accessed in October 2014) for the 75 Frio fields within 20 miles of the injection site are presented in Appendix 3.7.3-1. Table 3.7.3-I summarizes the Frio production data and organizes it by quarter quadrant location.

The IHS historical production totals were adjusted in Table 3.7.3-I to estimate equivalent reservoir volumes of oil and gas, as follows: reported volumes of produced oil were multiplied by 1.1, and the liquid equivalent of produced gas in thousands of cubic feet was estimated to be 1 reservoir barrel. A conservative volume of produced water was assumed to be the greater of the reported volume of water or the reported volume of oil. The estimated future productions is assumed to be 20% of the adjusted historical produced volume.

The volume of this fluid and the relative direction of the production were used to estimate the direction and distance the plume would be expected to move. To develop an effective sink term with which evaluation of motion due to withdrawal could be accomplished, the vector sum of production by quarter quadrant was calculated. Quarter quadrant direction (or a 22.5° arc centered on north, for example) was used for vector orientation. Production volume was used as the vector magnitude. By summing production for 360° around the site, a final equivalent value of 9,660.55 million equivalent reservoir barrels (MMRB) of production was calculated to have occurred at one location oriented approximately 2.8° west of south from the injection site, as detailed in Table 3.7.3-I.

Figure 3.7.3-2(A) is a top view of the production vectors for each quarter quadrant from Table 3.7.3-I, with the tail of each vector at the injection site and the head

pointing in the direction of the field(s). The length of each vector is in MMRB of production (also listed in Table 3.7.3-1). Figure 3.7.3-2(B) shows the vector sum (net production volume and direction) determined using the head-to-tail method of vector addition on a scaled drawing. In the head-to-tail method, the tail of the first vector (296.435 MMRB, NE) is drawn at the location of the injection wells, the tail of the second vector (294.775 MMRB, ENE) is drawn at the head of the first vector, and so on, until the last vector (8354.608 MMRB, SSW) is drawn. The net production vector sum (9,660.55 MMRB, S2.8°W) is the vector that begins at the tail of the first vector (at the injection site) and ends at the head of the last vector.

A conservative view of the effect of production is that, since a finite amount of fluid has been produced, a finite volume of fluid will flow into the pressure-depleted zone to replace the fluid withdrawn, assuming that water influx will not occur behind the depleted production, and at this point flow due to the withdrawal will cease. Thus, approximately 54.2440×10^9 cubic feet of fluid (9,660.55 MMRB) is required to fill the depleted production zone. Although a variety of approaches can be taken to address this fluid migration problem, a simple scenario is presented that provides a conservative overestimate for plume migration due to withdrawals.

The most conservative approach is to assume that a direct channel exists between the injection interval and the production interval and that all fluid required to fill the depleted zone must flow through this channel. This is an extremely conservative approach since the actual fluids available to flow into the depleted zone will flow from all directions radially (360°) toward the center of the depleted region.

Once the vector sum of the oil and gas production is calculated and centered in the direction S2.8°W, conservative estimates for the channel size are required. It is clear from the cross sections (Figures 2.1.4-1 and 2.1.4-2) that the zones from which fluids could be drawn extend throughout the review area, which extends at least 7 miles in all directions from the injection site. Since the fluid withdrawn from a 40-mile-diameter volume is considered, a reasonable width for the channel is 20 miles. Therefore, a channel 20 miles wide, with one end centered at the injection site, would provide a reasonably conservative estimate for channel width. Figure 3.7.3-2(C) shows the channel superimposed on the net production vector.

The next estimate that needs to be developed concerns the net thickness to be used through which fluid would flow. The net thickness of the sands of the Lower Frio injection interval is estimated to be approximately 350 feet or greater at this site, which accounts for approximately 60% of the net sand thickness of all of the Frio sands. The net thickness of the sands of the Upper and Middle Frio injection interval is also estimated to be greater than 350 feet at the site. A minimal value for effective porosity is chosen to be 0.26, even though the formation actually reflects porosity closer to 0.28, as indicated in Section 3.2.3.

Therefore, if the effective fluid volume is conservatively assumed to move directly from the injection interval to the production zone as a bank of fluid 350 feet high and 20 miles across [Figure 3.7.3-2(C)], and if the formation is considered to have a effective porosity of 0.26, then the following equation can be used to estimate plume migration due to oil and gas production at this site using a direct channel approach:

$$D = \frac{V}{5280 h L \phi} = \frac{52,244,000,000}{(5280)(350)(20)(0.26)} = 5645 \text{ feet}$$

where

- 5280 = conversion factor (miles to feet)
- D = plume migration distance (feet)
- V = volume of reservoir fluids produced (cubic feet)
- ϕ = zone porosity (dimensionless ratio)
- h = fluid bank height (feet)
- L = lateral fluid bank width (miles)

Using the information provided above, a plume migration of 5645 feet (1.1 miles) would be expected due to fluid withdrawals. This is considered to be an extreme worst-case scenario for several reasons. These include: reservoir production has been based on maximum estimates; flow from the injection site to the effective producing region was calculated as linear through a narrow channel instead of considering a radial field of flow into the depleted zone; the expansion of oil and gas as pressure declines due to production was not included; the producing Frio

Formation intervals are assumed to be in communication with either the Upper and Middle Frio injection interval or the Lower Frio injection interval; and a zone thickness less than the actual injection interval net sand thickness was used. Even in this worst-case demonstration, plume migration due to oil, gas, and water withdrawals from the Frio is minimal. To maximize the migration distances of the waste plumes, however, the southern boundaries of the waste plumes are extended by 5645 feet in the direction S2.8°W. Since the direction of plume migration due to oil, gas, and water production is opposite the updip direction of the low-density waste plume, to maximize the updip migration distance of the low-density waste plume, movement caused by oil, gas, and water production was ignored.

3.7.4 Dispersion and Diffusion Factors

Dispersion and molecular diffusion lead to smearing of the waste front and to the extension of concentration contours beyond the extent predicted by "plug-flow" movement due to injection and hydraulic gradients within the injection interval. The term dispersion refers to smearing of the front due to movement of the formation fluid, while diffusion refers to smearing due to Brownian motion of the molecules. Over short periods of time, when fluids are moved by injection, dispersion is greater than molecular diffusion. However, over the 10,000-year projection of plume migration, diffusion becomes increasingly significant. Diffusion up a brine-filled wellbore, over 10,000 years, determines the required thickness of the containment interval.

3.7.4.1 Dispersivity Coefficients, α_L and α_T

A review of the literature shows that a large number of authors have considered this problem in detail over the last few decades. (All dispersion-related papers referenced in this section are located in Appendix 3.7.4.1-1 of this document.) In 1979, Anderson (1979) prepared an excellent review article which summarized much of the work that had been accomplished previous to her review, and anticipated much of the work that would be accomplished in the 1980s. Basically, the work in this area has been divided into measuring

dispersivity on a variety of length scales in the field, and theoretically accounting for the observed field scale dependence.

One of the more productive theoretical approaches to calculating a coefficient of advective dispersion was discussed and analyzed by Gelhar (1986). Gelhar used the approach that dispersivity was a result of random hydraulic parameter fluctuations, or, more specifically, dispersivity could be related to the log-normal distribution of permeability and the associated variance for a given sand zone. It is important to note that Gelhar's theoretical evaluation, as well as other authors' interpretations, are not based on formation materials, but rather on permeability distributions within conductive systems (Walton, 1985).

Walton (1985, pages 34-39), in his discussion of dispersivity, presents the method developed by Pickens and Grisak (1981) for estimating the coefficient of dispersivity based on the total plume travel distance. Pickens and Grisak (1981) basically concluded that dispersivity in single layers was similar to laboratory values. However, diffusion between layers in the aquifer added significantly to the observed field dispersion over the complete aquifer thickness (Pickens and Grisak, 1981). Based on the data described in their paper, Pickens and Grisak (1981) concluded that the dispersivity coefficient for regional migration was a linear function of the migration distance over distances up to 1000 meters. In their paper, the coefficient of dispersivity was estimated to be approximately 10% of the plume migration distance. However, in deference to the discussions of Gelhar, et al. (1979) and Matheron and DeMarsily (1980), Pickens and Grisak (1981) concluded that at some point during plume migration a maximum coefficient for dispersivity would be approached asymptotically (also Walton, 1985, page 37).

Arya, et al. (1988) studied dispersion for the miscible displacement of one fluid by another in enhanced oil recovery processes. They state that on a megascopic scale (i.e., aquifer scale) dispersion results from contrasts in hydraulic conductivity. Generally, larger contrasts result in larger dispersion. They present a plot of megascopic dispersivities versus travel distance. The data,

while considerably scattered, confirm that dispersivity increases with travel distance. A least-squares fit of their reported field data is:

$$\alpha_L = 0.229 L^{0.755}$$

where L is the length over which dispersivity was measured and α_L is the average dispersivity. With the exception of one data point, their plot of dispersivities indicates that a value of roughly 300 feet is a maximum. They also conclude, based on theoretical considerations, that dispersivity is proportional to distance. The proportionality constant depends upon time, distance and the Dykstra-Parsons (1950) coefficient (a measure of heterogeneity). The proportionality constant ranges from less than 0.01 for fairly homogeneous systems to approximately 0.09 for very heterogeneous systems. They also conclude that diffusion does not influence megascopic dispersivity.

Lake (1989), in dealing with the subject of enhanced oil recovery, states that longitudinal dispersivity is a measure of the local heterogeneity scale and that field-derived values of dispersivity are far less certain than those obtained in laboratory settings.

Based on the foregoing review of field and laboratory dispersivity studies, the following procedure was adopted for determining the values of dispersivity to use in modeling:

1. Based on the mean travel distance at 10,000 years, derived from preliminary modeling, determine the longitudinal dispersivity using the following equation from Arya, et al. (1988):

$$\alpha_L = 0.229 L^{0.755}$$

2. If the calculated value of α_L is less than an asymptotic maximum of 300 feet, the model may be rerun using the lesser value. Examination of the above equation shows that α_L reaches the asymptotic value of 300 feet whenever L is greater than approximately 13,500 feet.

3. Based on the reporting of Anderson (1979), a reasonable ratio of transverse to longitudinal dispersivity is about 0.2. Therefore, an asymptotic value of 60 feet is indicated for α_T .

For the injection site, preliminary updip modeling runs utilizing SWIFT indicated migration distances, for the core of the plume, in excess of 30,000 feet. Table 3.7.4.1-I presents observed dispersivity data, extracted from Figure 5.17 of Lake, 1989, for migration distances greater than 10,000 feet. One of these values is for fractured media and is considered inappropriate as a basis for estimating dispersivity in the area of the site. The rest of the values have an arithmetic mean value of 509 feet. The above discussion indicates that a median estimate for longitudinal dispersivity at large scales of migration is 300 feet or greater. However, to provide additional conservatism in projecting longitudinal migration, a longitudinal dispersivity value of 160 feet was chosen. A 2:1 ratio of longitudinal to transverse dispersivity ($\alpha_L = 160$ feet, $\alpha_T = 80$ feet) was selected for the base case modeling runs. A 5:1 ratio of longitudinal to transverse dispersivity ($\alpha_L = 160$ feet, $\alpha_T = 32$ feet) was selected for the updip sensitivity run.

3.7.4.2 Diffusion Coefficients

In defining the most conservative case for molecular diffusion, the lowest C/C_0 of 7×10^{-11} was combined with the largest possible diffusion coefficient. The maximum diffusion distance calculated in Section 5.3.2.2 is the greatest distance that can be calculated for any petitioned constituent. The maximum diffusion distance was calculated by combining the diffusion coefficient for the fastest-diffusing constituent considered and the C/C_0 for the constituents with the minimum C/C_0 . Using this method is conservative. This method yields a larger vertical diffusion distance than could be calculated for any individual petitioned constituent, because no single constituent has both the greatest diffusion coefficient and the minimum C/C_0 .

The largest diffusion coefficient for hazardous inorganic constituents listed in Lerman (1979, Appendix 3.7.4.2-1), is $20.1 \times 10^{-6} \text{ cm}^2/\text{s}$ ($1.87 \times 10^{-3} \text{ ft}^2/\text{day}$) for thallium ion. The effective diffusion coefficient is temperature-dependent and should be converted to the estimated reservoir temperature from Section 3.2.5. Reid et al. (1987, Appendix 3.7.4.2-2) gives the following equation to calculate the change in the diffusion coefficient due to temperature change.

$$\frac{D_o(T_2)}{D_o(T_1)} = \left(\frac{T_c - T_1}{T_c - T_2} \right)^n \quad \text{Equation 3.7.4.2-1}$$

where

- $D_o(T_2)$ = free-water diffusivity at T_2
- $D_o(T_1)$ = free-water diffusivity at T_1
- T_c = critical temperature ($^{\circ}\text{K}$) of solvent (water)
- T_1 = temperature ($^{\circ}\text{K}$) with known D_o
- T_2 = temperature ($^{\circ}\text{K}$) where D_o is to be calculated
- n = exponent dependent upon solvent's heat of vaporization

The critical temperature of water is 647.3°K and $n = 6$ for water. T_1 is 25°C or 298.15°K , T_2 is the formation temperature.

The diffusion coefficient for thallium is calculated at two temperatures, 151.8°F (66.56°C , 339.71°K), which is the temperature at the top of the Upper and Middle Frio injection interval, and 176.5°F (80.28°C , 353.43°K), which is the temperature at the top of Sand 6 in the Lower Frio injection interval.

Inserting the appropriate values into Equation 3.7.4.2-1 and solving for the diffusion coefficient at 151.8°F (top of Upper and Middle Frio injection interval) and 176.5°F (top of Sand 6) yields:

$$\frac{D_o(T_2)}{20.1 \times 10^{-6} \text{ cm}^2/\text{s}} = \left(\frac{647.3^\circ\text{K} - 298.15^\circ\text{K}}{647.3^\circ\text{K} - T_2} \right)^6 \quad \text{Equation 3.7.4.2-2}$$

and D_o at 151.8°F :

$$D_o(151.8^\circ\text{F}) = 4.300 \times 10^{-5} \text{ cm}^2/\text{s} \text{ or } 1.460 \text{ ft}^2/\text{yr} \quad \text{Equation 3.7.4.2-3}$$

and D_o at 176.5°F :

$$D_o(176.5^\circ\text{F}) = 5.654 \times 10^{-5} \text{ cm}^2/\text{s} \text{ or } 1.919 \text{ ft}^2/\text{yr} \quad \text{Equation 3.7.4.2-4}$$

For organic compounds, the methods of Hayduk and Laudie (1974, Appendix 3.7.4.2-3) and Lyman et al. (1990, Appendix 3.7.4.2-4) can be used to calculate the greatest diffusion coefficient. Formaldehyde (CH_2O) is the smallest organic compound in Table 3.5.1-I. The Le Bas molar volume for formaldehyde is calculated according to Lyman (1990, Appendix 3.7.4.2-5) as follows:

$$\begin{aligned} 1 \times 14.8 &= 14.8 \text{ (1 carbon)} \\ 2 \times 3.7 &= 7.4 \text{ (2 hydrogens)} \\ 1 \times 7.4 &= \underline{7.4} \text{ (1 oxygen)} \\ &= 29.6 \text{ cm}^3/\text{mole} \end{aligned} \quad \text{Equation 3.7.4.2-5}$$

The free-water diffusivity for formaldehyde is calculated using Equation 3.7.4.2-6. The source of Equation 3.7.4.2-6 is Hayduk and Laudie, 1974, in Appendix 3.7.4.2-3).

$$D_o = \frac{13.26 \times 10^{-5}}{\mu^{1.4} V^{0.589}} \quad \text{Equation 3.7.4.2-6}$$

where

D_o = diffusion coefficient at reservoir temperature

V = molar volume of formaldehyde, 29.6 cm³/mole from Equation 3.7.4.2-5

μ = viscosity of water at reservoir temperature

Substituting the viscosity of reservoir brine at 151.8°F (top of Upper and Middle Frio injection interval), 0.5345 cp, from Table 3.4.4-I, into Equation 3.7.4.2-6 gives:

$$D_o = \frac{13.26 \times 10^{-5}}{(0.5345 \text{ cp})^{1.4} (29.6 \text{ cm}^3/\text{mole})^{0.589}} \quad \text{Equation 3.7.4.2-7}$$
$$= 4.333 \times 10^{-5} \text{ cm}^2/\text{s} \text{ or } 1.471 \text{ ft}^2/\text{year}$$

Substituting the viscosity of reservoir brine at 176.5°F (top of Sand 6), 0.4509 cp, from Table 3.4.4-I, into Equation 3.7.4.2-6 gives:

$$D_o = \frac{13.26 \times 10^{-5}}{(0.4509 \text{ cp})^{1.4} (29.6 \text{ cm}^3/\text{mole})^{0.589}} \quad \text{Equation 3.7.4.2-8}$$
$$= 5.498 \times 10^{-5} \text{ cm}^2/\text{s} \text{ or } 1.866 \text{ ft}^2/\text{year}$$

The effect of temperature, calculated explicitly for thallium using Equations 3.7.4.2-2 through 3.7.4.2-4, is included implicitly in the estimate of diffusion coefficient for formaldehyde using Equations 3.7.4.2-6 through 3.7.4.2-8. In Equation 3.7.4.2-6, the effect of temperature is accounted for by using the formation fluid viscosity at the formation temperature from Table 3.4.4-I or 0.5345 cp at 151.8°F (top of the Upper and Middle Frio injection interval) and 0.4509 cp at 176.5°F (top of Sand 6).

Comparing the greatest free-water diffusion coefficients for inorganics and organics at 151.8°F (top of Upper and Middle Frio injection interval), the larger free-water diffusion coefficient is that for formaldehyde, 1.471 ft²/yr (0.004030 ft²/day). At 176.5°F (top of Sand 6), the larger free-water diffusivity is that for thallium, 1.919 ft²/yr (0.005258 ft²/day). Using the largest diffusion coefficient for each temperature will result in the greatest diffusion distance for the waste constituents that compose Vopak's currently approved or requested waste codes.

Modeling of plume migration with SWIFT requires an effective molecular diffusivity, DMEFF:

$$DMEFF = \phi \tau D \quad \text{Equation 3.7.4.2-9}$$

where

ϕ = porosity, fraction

τ = tortuosity, square of the ratio of the straight-line distance to actual distance traveled

D = fluid molecular diffusion ft²/day

The Millington formula (Maidment, 1993; Appendix 3.7.4.2-5) is used to determine the tortuosity:

$$\phi D_{\text{eff}} = \frac{\theta_s^{10/3}}{\phi^2} D \quad \text{Equation 3.7.4.2-10}$$

where

ϕ = porosity

θ_s = solute saturation

It should be noted that $\theta_s + \theta_B = \phi$, where θ_B is the portion of porosity occupied by reservoir brine.

In addition, the following equation is used to extract a tortuosity from the Millington formula:

$$\phi D_{\text{eff}} = \theta_s \tau D \quad \text{Equation 3.7.4.2-11}$$

Combining the two previous equations results in the tortuosity

$$\begin{aligned} \frac{\theta_s^{10/3}}{\phi^2} D &= \theta_s \tau D \\ \theta_s \left(\frac{\theta_s^{7/3}}{\phi^2} \right) D &= \theta_s \tau D \\ \tau &= \left(\frac{\theta_s^{7/3}}{\phi^2} \right) \end{aligned} \quad \text{Equation 3.7.4.2-12}$$

Preliminary simulation runs to establish parameters indicated the migrated core of the low-density plume had a concentration of 0.2542, while the migrated core of the high-density plume had a concentration of 0.8901. The pertinent pages of the preliminary output are presented in Appendices 3.7.4.2-6 and 3.7.4.2-7 for the Lower Frio injection interval light and heavy plume models. The pore space occupied by the low-density plume, based on a porosity of 0.28, is 0.07118 (0.2542 x 0.28), which results in a tortuosity of 0.02678:

$$\begin{aligned} \tau &= \frac{(0.07118)^{7/3}}{(0.28)^2} \\ &= 0.02678 \end{aligned}$$

For the high-density plume, the occupied pore space is 0.2492 (0.8901 x 0.28), which results in a tortuosity of 0.4985:

$$\tau = \frac{(0.2492)^{7/3}}{(0.28)^2}$$

$$= 0.4985$$

The DMEFF parameter used in the SWIFT input for the Lower Frio low-density model is then calculated to be 0.00003943 ft²/day (0.28 x 0.02678 x 5.258 x 10⁻³ ft²/day). The DMEFF value for the Lower Frio high-density model is 0.0007207 ft²/day (0.28 x 0.4895 x 5.258 x 10⁻³ ft²/day).

The preliminary runs for the Upper and Middle Frio injection interval plume models indicated the migrated cores of the low-density and high-density plumes had concentrations of 0.04396 and 0.3509, respectively. Excerpts of the simulation output are presented in Appendices 3.7.4.2-8 and 3.7.4.2-9. The resulting tortuosity for the Upper and Middle Frio low-density model was 0.0004463 resulting in a value of 5.036 x 10⁻⁷ ft²/day (0.28 x 0.0004463 x 4.030 x 10⁻³ ft²/day) for the DMEFF parameter. The tortuosity of the Upper and Middle Frio high-density model was 0.05681, resulting in a DMEFF value of 6.410 x 10⁻⁵ ft²/day.

3.7.5 Critical Pressure Rise

The COI for this site is calculated by considering the presence of 9.0-pound-per-gallon (lb/gal) mud that extends to 50 feet from the ground surface in an abandoned well.

Upper and Middle Frio Injection Interval - Based on a depth of 5517 feet BGL to the top of the Upper and Middle Frio injection interval, a 9.0-lb/gal mud 50 feet from the ground surface would produce a hydrostatic head of 2558.56 psi.

$$P_m = \text{Height of Mud Column} \times \text{Mud Pressure Gradient}$$

$$= (5517 \text{ feet} - 50 \text{ feet})(9.0 \text{ lb/gal})(0.052 \frac{\text{psi/ft}}{\text{lb/gal}})$$

$$= 2558.56 \text{ psig}$$

A mud gel strength (see Section 8.2) of 20 lb/100 ft² in a 12-inch wellbore would add an additional 30.34 psi, calculated using the equation below (derived from Johnston and Knappe 1986, page 10; Appendix 8.2-1).

$$P_g = \frac{(3.33 \text{ ft-in})(20 \text{ psi}/100 \text{ ft}^2)(5517 \text{ feet} - 50 \text{ feet})}{(12 \text{ in})(1000)}$$

$$= 30.34 \text{ psi}$$

Thus, a 9.0-lb/gal mud column in a 12-inch wellbore will provide 2588.90 psi (or 2558.56 psi + 30.34 psig) of resistance to fluid flow from the injection reservoir. Considering an initial reservoir pressure of 2372.38 psia (2358.68 psig) at a reference depth of 5517 feet BGL (Section 3.2.6), and disregarding other mitigating conditions, the COI would be defined by the critical pressure rise of 230.22 psi (2588.90 psig – 2358.68 psig).

Lower Frio Injection Interval - For the Lower Frio injection interval, with the top of Sand 1 at 6862 feet BGL, the critical pressure rise is similarly calculated to be 248.48 psi.

$$P_m = (6862 \text{ feet BGL} - 50 \text{ feet}) \times 9.0 \text{ lb/gal} \times 0.052 \text{ (psi/ft)} / (\text{lb/gal})$$

$$= 3188.01 \text{ psi}$$

$$P_g = (3.33 \text{ ft-in})(20 \text{ psi}/100 \text{ ft}^2)(6862 \text{ feet BGL} - 50 \text{ feet}) / [(12 \text{ in})(1000)]$$

$$= 37.81 \text{ psi}$$

$$P_i = 2977.34 \text{ psig from Section 3.2.6}$$

$$\text{Critical Pressure Rise} = 3188.01 \text{ psi} + 37.81 \text{ psi} - 2977.34 \text{ psig}$$

$$= 248.48 \text{ psi}$$

The positions of the COI boundaries for the wells are illustrated on Figures 5.1.4-1 through 5.1.4-11 and 8.1-1.

3.7.6 Class II Injection Wells Near the Facility's Class I Wells

Four (4) Class II injection wells (saltwater disposal wells [SWDs]) were identified in or near the cone of influence and the plume migration path of the facility's injection wells, as indicated in Section 8.4, Table 8.4-I, Attachment B, and/or on Figure 8.1-1. Table 3.7.6-I lists the Class II injection wells, the depths of the perforated injection interval, and the date that each well was completed as, or converted to, a saltwater disposal well. The injection intervals in the Class II wells were examined to determine if they correlate to the injection interval sands into which the injection facility's Class I wells are completed. All four of the Class II wells are completed in the Lower Frio injection interval sands, as shown in Table 3.7.6-I. Electric logs that are readily available for the Class II wells are included in Attachment B. The Class II well for which the electric log is included is Control No. 110.

Class II Wells Completed in the Lower Frio Injection Interval – Four (4) Class II wells are completed in the Lower Frio injection interval sands. The wells are Control Nos. 110, 127, 139, and 166. The history of each well is discussed below.

Control No. 110, the Etoco Incorporated Sam Houston Unit Well No. 4, was drilled in 2001 and converted to a Class II well in January 2002. The well is located approximately 2.7 miles west-northwest of the facility's Class I wells. The permitted injection interval is within the Lower Frio injection interval sands, from 6948 feet to 7350 feet BGL, according to the RRC disposal permit, included in Attachment B. The well is currently perforated from 7300 feet KB to 7350 feet KB. The log for the well is included in Attachment B. The permitted maximum injection rate is 10,000 barrels/day or 292 gpm. Actual average monthly injection rates have not exceeded 74 gpm, the average rate for August 2004, as shown in Tables 3.7.6-II and 5.1.2-IV. During 2005 and 2006, the maximum average monthly injection rate did not exceed 27 gpm. Since June 2006, the maximum average monthly injection rate has been less than 1.7 gpm.

Control No. 127, the Thorp Petroleum Corporation Texas Northern Railway No. 6, was drilled as a Class II well in October 1999. The well is located approximately

3.2 miles north of the facility's Class I wells. The permitted injection interval is within the Lower Frio injection interval sands, from 5999 feet to 7205 feet BGL, according to the RRC disposal permit, included in Attachment B. The well is currently perforated from 7035 feet true vertical depth (TVD) to 7181 feet TVD. The permitted maximum injection rate is 1,000 barrels/day or an average of 29.17 gpm. Actual average monthly injection rates have not exceeded 2.6 gpm since September 2002, as shown in Tables 3.7.6-II and 5.1.2-IV. Control No. 127 was plugged and abandoned on February 22, 2013. For conservatism the future injection rate for Control No. 127 in the reservoir modeling is 29.17 gpm.

Control No. 139, the Etoco Incorporated Destec No. 2D, was drilled as a Class II well in January 2005. The well is located approximately 2.7 miles west of the facility's Class I wells. The permitted injection interval is within the Lower Frio injection interval sands, from 6515 feet to 7094 feet BGL, according to the RRC disposal permit, included in Attachment B. The permitted maximum injection rate is 2,000 barrels/day or an average of 58.33 gpm. Actual average monthly injection rates are shown in Tables 3.7.6-II and 5.1.2-IV.

Control No. 166, the Etoco Incorporated Jackson-Peace No. 1D, was converted to a Class II well on March 9, 2005. The well is located approximately 5 miles north-northeast of the facility's Class I wells. The permitted injection interval is within the Lower Frio injection interval sands, from 6460 feet to 7346 feet BGL, according to the RRC disposal permit, included in Attachment B. The permitted injection rate is 3000 barrels/day or an average of 87.50 gpm. Actual average monthly injection rates are shown in Table 5.1.2-IV.

The injected volumes of Control Nos. 110, 127, 139, and 160 were included in the reservoir modeling, as discussed in Section 5.0. Control No. 110 and 127 have injected either no fluid or at average monthly rates of less than 2.6 gpm for at least 2 years. The predicted future rate for Control No. 110 is 0 gpm. The predicted future rates for Control Nos. 127, 139, and 166 are 29.17 gpm, 58.33 gpm, and 87.50 gpm, respectively, the maximum permitted average rate. The injection rates used in the reservoir modeling for Control Nos. 110, 127, 139, and 166 are presented in Table 5.1.2-IV.